414 Nicollet Mall
Minneapolis, MN 55401

Oct. 28, 2010

XCEL ENERGY
THIRD QUARTER 2010 EARNINGS

- Ongoing 2010 third quarter diluted earnings per share were $0.62 compared with $0.48 per share in 2009.
- GAAP (generally accepted accounting principles) 2010 third quarter diluted earnings per share were $0.67 compared with $0.48 per share in 2009.
- Xcel Energy reaffirms its 2010 ongoing earnings guidance of $1.55 to $1.65 per share and expects earnings to be in the upper half of the range.
- Xcel Energy initiates 2011 ongoing earnings guidance of $1.65 to $1.75 per share.

MINNEAPOLIS — Xcel Energy Inc. (NYSE: XEL) today reported third quarter 2010 GAAP earnings of $312 million, or $0.67 per diluted share, compared with third quarter 2009 GAAP earnings of $221 million, or $0.48 per diluted share.

Third quarter 2010 ongoing earnings, which exclude adjustments for certain non-recurring items, were $0.62 per share, compared with $0.48 per share in 2009. Ongoing earnings for the third quarter of 2010 increased primarily due to warmer temperatures, rate increases, the timing of revenue collection due to implementation of seasonal rates and a lower effective tax rate. Temperatures for the third quarter of 2010 were warmer than normal, while temperatures in the third quarter of 2009 were cooler than normal.

“We are pleased with strong third quarter results,” said Richard C. Kelly, chairman and chief executive officer. “Operationally, our system reliability remains strong despite severe weather and unseasonably warm temperatures. This is a result of the ongoing investments we have made in our system. While we anticipate the partial reversal of the timing impacts of seasonal rates in the fourth quarter, our year to date earnings continue to outpace last year. As a result, we are reaffirming our 2010 ongoing earnings guidance of $1.55 to $1.65 per share and we expect earnings to be in the upper half of the guidance range. In addition, we are initiating 2011 ongoing earnings guidance of $1.65 to $1.75 per share.”

Earnings Adjusted for Certain Non-recurring Items (Ongoing Earnings)

The following table provides a reconciliation of ongoing earnings per share to GAAP earnings per share:

	Three Months Ended Sept. 30,		Nine Months Ended Sept. 30,	
Diluted Earnings (Loss) Per Share	**2010**	**2009**	**2010**	**2009**
Ongoing[(a)] diluted earnings per share	$ **0.62**	$ **0.48**	$ **1.34**	$ **1.12**
COLI settlement, PSRI and Medicare Part D [(a)]	0.05	-	(0.01)	(0.01)
Earnings per share from continuing operations	**0.67**	**0.48**	**1.33**	**1.11**
Earnings per share from discontinued operations	-	-	0.01	-
GAAP diluted earnings per share	$ **0.67**	$ **0.48**	$ **1.34**	$ **1.11**

(a) See Note 7.

At 9 a.m. CST today, Xcel Energy will host a conference call to review financial results. To participate in the call, please dial in 5 to 10 minutes prior to the start and follow the operator's instructions.

US Dial-In:	(800) 762-8795
International Dial-In:	(480) 629-9773
Conference ID:	4371950

The conference call also will be simultaneously broadcast and archived on Xcel Energy's website at www.xcelenergy.com. To access the presentation, click on Investor Information. If you are unable to participate in the live event, the call will be available for replay from 12:00 p.m. CST on Oct. 28 through 11:59 p.m. CST on Oct. 29.

Replay Numbers

US Dial-In:	(800) 406-7325
International Dial-In:	(303) 590-3030
Access Code:	4371950#

Except for the historical statements contained in this release, the matters discussed herein, including our 2010 and 2011 full year earnings per share guidance and assumptions, are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements are intended to be identified in this document by the words "anticipate," "believe," "estimate," "expect," "intend," "may," "objective," "outlook," "plan," "project," "possible," "potential," "should" and similar expressions. Actual results may vary materially. Forward-looking statements speak only as of the date they are made, and we do not undertake any obligation to update them to reflect changes that occur after that date. Factors that could cause actual results to differ materially include, but are not limited to: general economic conditions, including the availability of credit and its impact on capital expenditures and the ability of Xcel Energy and its subsidiaries to obtain financing on favorable terms; business conditions in the energy industry; actions of credit rating agencies; competitive factors, including the extent and timing of the entry of additional competition in the markets served by Xcel Energy and its subsidiaries; unusual weather; effects of geopolitical events, including war and acts of terrorism; state, federal and foreign legislative and regulatory initiatives that affect cost and investment recovery, have an impact on rates or have an impact on asset operation or ownership or imposed environmental compliance conditions; structures that affect the speed and degree to which competition enters the electric and natural gas markets; costs and other effects of legal and administrative proceedings, settlements, investigations and claims; actions of accounting regulatory bodies; and the other risk factors listed from time to time by Xcel Energy in reports filed with the Securities and Exchange Commission (SEC), including Risk Factors in Item 1A and Exhibit 99.01 of Xcel Energy's Annual Report on Form 10-K for the year ended Dec. 31, 2009 and on Xcel Energy's Quarterly Report on Form 10-Q for the quarters ended March 31, and June 30, 2010.

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Xcel Energy Internet address: www.xcelenergy.com

This information is not given in connection with any sale, offer for sale or offer to buy any security.

XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME (Unaudited)
(amounts in thousands, except per share data)

	Three Months Ended Sept. 30, 2010	Three Months Ended Sept. 30, 2009	Nine Months Ended Sept. 30, 2010	Nine Months Ended Sept. 30, 2009
Operating revenues				
Electric	$ 2,440,917	$ 2,128,955	$ 6,477,211	$ 5,749,207
Natural gas	170,594	169,601	1,210,154	1,224,161
Other	17,276	16,006	56,648	52,819
Total operating revenues	2,628,787	2,314,562	7,744,013	7,026,187
Operating expenses				
Electric fuel and purchased power	1,110,781	982,103	3,085,347	2,703,952
Cost of natural gas sold and transported	66,571	71,638	774,647	809,791
Cost of sales — other	8,848	4,915	21,244	14,268
Other operating and maintenance expenses	509,634	466,465	1,507,247	1,410,760
Conservation and demand side management program expenses	60,861	47,157	174,451	133,793
Depreciation and amortization	221,671	198,222	639,303	609,285
Taxes (other than income taxes)	81,791	78,914	244,175	229,025
Total operating expenses	2,060,157	1,849,414	6,446,414	5,910,874
Operating income	568,630	465,148	1,297,599	1,115,313
Other income (expense), net	27,450	(977)	30,134	4,394
Equity earnings of unconsolidated subsidiaries	7,670	4,363	22,433	10,760
Allowance for funds used during construction — equity	13,464	18,618	39,750	55,565
Interest charges and financing costs				
Interest charges — includes other financing costs of $5,229 $5,103, $15,386 and $15,255 respectively	144,849	139,347	430,134	420,447
Allowance for funds used during construction — debt	(6,323)	(9,598)	(20,635)	(29,671)
Total interest charges and financing costs	138,526	129,749	409,499	390,776
Income from continuing operations before income taxes	478,688	357,403	980,417	795,256
Income taxes	166,200	135,610	364,964	280,581
Income from continuing operations	312,488	221,793	615,453	514,675
Income (loss) from discontinued operations, net of tax	(182)	(965)	3,747	(2,673)
Net income	312,306	220,828	619,200	512,002
Dividend requirements on preferred stock	1,060	1,060	3,180	3,180
Earnings available to common shareholders	$ 311,246	$ 219,768	$ 616,020	$ 508,822
Weighted average common shares outstanding:				
Basic	460,471	456,769	459,816	456,095
Diluted	462,019	457,453	460,722	456,729
Earnings per average common share — basic:				
Income from continuing operations	$ 0.68	$ 0.48	$ 1.33	$ 1.12
Income from discontinued operations	-	-	0.01	-
Earnings per share	$ 0.68	$ 0.48	$ 1.34	$ 1.12
Earnings per average common share — diluted:				
Income from continuing operations	$ 0.67	$ 0.48	$ 1.33	$ 1.11
Income from discontinued operations	-	-	0.01	-
Earnings per share	$ 0.67	$ 0.48	$ 1.34	$ 1.11
Cash dividends declared per common share	$ 0.25	$ 0.25	$ 0.75	$ 0.73

Due to the seasonality of Xcel Energy's operating results, quarterly financial results are not an appropriate base from which to project annual results.

Note 1. Earnings per Share Summary

The following table summarizes the diluted earnings per share for Xcel Energy:

	Three Months Ended Sept. 30,		Nine Months Ended Sept. 30,	
Diluted Earnings (Loss) Per Share	**2010**	**2009**	**2010**	**2009**
Public Service Company of Colorado (PSCo)	$ 0.29	$ 0.20	$ 0.69	$ 0.51
NSP-Minnesota	0.24	0.20	0.48	0.48
Southwestern Public Service Company (SPS)	0.08	0.08	0.16	0.14
NSP-Wisconsin	0.04	0.03	0.08	0.08
Equity earnings of unconsolidated subsidiaries	0.01	0.01	0.03	0.02
Regulated utility — continuing operations [b]	0.66	0.52	1.44	1.23
Holding company and other costs	(0.04)	(0.04)	(0.10)	(0.11)
Ongoing[a] diluted earnings per share	**0.62**	**0.48**	**1.34**	**1.12**
COLI settlement, PSRI and Medicare Part D [a]	0.05	-	(0.01)	(0.01)
Earnings per share from continuing operations	**0.67**	**0.48**	**1.33**	**1.11**
Earnings per share from discontinued operations	-	-	0.01	-
GAAP diluted earnings per share	**$ 0.67**	**$ 0.48**	**$ 1.34**	**$ 1.11**

(a) See Note 7.
(b) See Note 2.

PSCo — Earnings at PSCo increased by $0.09 per share for the third quarter and by $0.18 per share for the nine months ended Sept. 30, 2010. The increases are primarily due to rate increases, the timing of revenue collection as a result of the implementation of seasonal rates in June 2010 and warmer temperatures, which increased electric sales. The increase was partially offset by higher operating and maintenance (O&M) expenses and depreciation expense. Seasonal rates are designed to be revenue neutral on an annual basis. As a result, the quarterly pattern of revenue collection is expected to be different than in the past as seasonal rates are higher in the summer months and lower throughout the remainder of the year. Therefore, it is anticipated that this positive revenue and margin trend will partially reverse in the fourth quarter.

NSP-Minnesota — Earnings at NSP-Minnesota increased by $0.04 per share for the third quarter and were flat for the nine months ended Sept. 30, 2010. The third quarter increase is largely due to the positive impact of warmer temperatures and weather normalized sales growth, partially offset by higher O&M expenses and depreciation expense.

SPS — Earnings at SPS were flat for the third quarter and increased by $0.02 per share for the nine months ended Sept. 30, 2010. The year to date increase is mainly due to electric sales growth, which was partially offset by higher O&M expenses.

NSP-Wisconsin — Earnings at NSP-Wisconsin increased by $0.01 per share for the third quarter and were flat for the nine months ended Sept. 30, 2010. The third quarter increase is due to warmer temperatures which increased electric sales, as well as new electric rates, which were effective in January 2010, partially offset by higher O&M expenses.

The following table summarizes significant components contributing to the changes in the 2010 diluted earnings per share compared with the same periods in 2009, which are discussed in more detail later in the release.

Diluted Earnings (Loss) Per Share	Three Months Ended Sept. 30,	Nine Months Ended Sept. 30,
2009 GAAP diluted earnings per share	**$ 0.48**	**$ 1.11**
PSRI	-	0.01
2009 ongoing[(a)] diluted earnings per share	**0.48**	**1.12**
Components of change — 2010 vs. 2009		
Higher electric margins	0.24	0.46
Higher natural gas margins	0.01	0.03
Higher operating and maintenance expenses	(0.06)	(0.13)
Higher depreciation and amortization	(0.03)	(0.04)
Higher conservation and DSM expenses (generally offset in revenues)	(0.02)	(0.05)
Lower AFUDC — equity	(0.01)	(0.03)
Higher taxes (other than income taxes)	-	(0.02)
Other, net	0.01	-
2010 ongoing[(a)] diluted earnings per share	**0.62**	**1.34**
COLI settlement, PSRI and Medicare Part D [(a)]	0.05	(0.01)
2010 earnings per share from continuing operations	**0.67**	**1.33**
Earnings per share from discontinued operations	-	0.01
2010 GAAP diluted earnings per share	**$ 0.67**	**$ 1.34**

(a) See Note 7.

Note 2. Regulated Utility Results — Continuing Operations

Estimated Impact of Temperature Changes on Regulated Earnings — Unseasonably hot summers or cold winters increase electric and natural gas sales while, conversely, mild weather reduces electric and natural gas sales. The estimated impact of weather on earnings is based on the number of customers, temperature variances and the amount of natural gas or electricity the average customer historically uses per degree of temperature. Accordingly, deviations in weather from normal levels can affect Xcel Energy's financial performance.

Degree-day or Temperature-Humidity Index (THI) data is used to estimate amounts of energy required to maintain comfortable indoor temperature levels based on each day's average temperature and humidity. Heating degree-days (HDD) is the measure of the variation in the weather based on the extent to which the average daily temperature falls below 65° Fahrenheit, and cooling degree-days (CDD) is the measure of the variation in the weather based on the extent to which the average daily temperature rises above 65° Fahrenheit. Each degree of temperature above 65° Fahrenheit is counted as one cooling degree-day, and each degree of temperature below 65° Fahrenheit is counted as one heating degree-day. In Xcel Energy's more humid service territories, a THI is used in place of CDD, which adds a humidity factor to CDD. HDD, CDD and THI are most likely to impact the usage of Xcel Energy's residential and commercial customers. Industrial customers are less weather sensitive.

Normal weather conditions are defined as either the 20-year or 30-year average of actual historical weather conditions. The historical period of time used in the calculation of normal weather differs by jurisdiction based on the time period used by the regulator in establishing estimated volumes in the rate setting process. The percentage increase (decrease) in normal and actual HDD, CDD and THI for the three and nine months ended Sept. 30, 2010 and 2009 are provided in the following table:

	Three Months Ended Sept. 30,			Nine Months Ended Sept. 30,		
	2010 vs. Normal	2009 vs. Normal	2010 vs. 2009	2010 vs. Normal	2009 vs. Normal	2010 vs. 2009
HDD	(30.1) %	(24.7) %	(7.1) %	(3.7) %	(2.7) %	(1.1) %
CDD	8.8	(11.8)	23.3	11.4	(10.0)	23.8
THI	35.7	(41.4)	131.4	28.3	(34.0)	94.4

The following table summarizes the estimated impact on earnings per share of temperature variations compared with sales under normal weather conditions:

	Three Months Ended Sept. 30,			Nine Months Ended Sept. 30,		
	2010 vs. Normal	2009 vs. Normal	2010 vs. 2009	2010 vs. Normal	2009 vs. Normal	2010 vs. 2009
Retail electric	$ 0.04	$ (0.05)	$ 0.09	$ 0.05	$ (0.05)	$ 0.10
Firm natural gas	0.00	0.00	0.00	(0.01)	(0.01)	0.00
Total	$ 0.04	$ (0.05)	$ 0.09	$ 0.04	$ (0.06)	$ 0.10

Sales Growth (Decline) — The following table summarizes Xcel Energy's sales growth (decline) for actual and weather-normalized sales for 2010 as compared with the same periods in 2009.

	Three Months Ended Sept. 30,		Nine Months Ended Sept. 30,	
	Actual	Normalized	Actual	Normalized
Electric residential	13.1 %	0.1 %	7.3 %	1.4 %
Electric commercial and industrial	5.0	1.5	2.9	1.4
Total retail electric sales	7.3	1.2	4.1	1.4
Firm natural gas sales	(5.1)	(1.9)	2.2	0.4

Electric — Electric revenues and fuel and purchased power expenses are largely impacted by the fluctuation in the price of natural gas, coal and uranium used in the generation of electricity, but as a result of the design of fuel recovery mechanisms to recover current expenses, these price fluctuations have little impact on electric margin. The following tables detail the electric revenues and margin:

	Three Months Ended Sept. 30,		Nine Months Ended Sept. 30,	
(Millions of Dollars)	2010	2009	2010	2009
Electric revenues	$ 2,441	$ 2,129	$ 6,477	$ 5,749
Electric fuel and purchased power	(1,111)	(982)	(3,085)	(2,704)
Electric margin	$ 1,330	$ 1,147	$ 3,392	$ 3,045

The following table summarizes the components of the changes in electric margin:

(Millions of Dollars)	Three Months Ended Sept. 30, 2010 vs. 2009	Nine Months Ended Sept. 30, 2010 vs. 2009
Retail rate increases, including seasonal rates (Colorado, Wisconsin, South Dakota and New Mexico)	$ 88	$ 210
Estimated impact of weather	58	69
NSP-Minnesota 2009 rate case adjustment for final rates (largely offset in depreciation expense)	25	-
Non-fuel riders	13	9
Conservation and DSM revenue and incentive (partially offset by expenses)	11	39
Retail sales increase (excluding weather impact)	4	18
Sales mix and demand revenue	(4)	13
Other, net (including trading and deferred fuel adjustments)	(12)	(11)
Total increase in electric margin	$ 183	$ 347

Natural Gas — The cost of natural gas tends to vary with changing sales requirements and the cost of natural gas purchases. However, due to the design of purchased natural gas cost recovery mechanisms to recover current expenses for sales to retail customers, fluctuations in the cost of natural gas have little effect on natural gas margin. The following tables detail natural gas revenues and margin:

	Three Months Ended Sept. 30,		Nine Months Ended Sept. 30,	
(Millions of Dollars)	2010	2009	2010	2009
Natural gas revenues	$ 171	$ 170	$ 1,210	$ 1,224
Cost of natural gas sold and transported	(67)	(72)	(775)	(810)
Natural gas margin	$ 104	$ 98	$ 435	$ 414

The following table summarizes the components of the changes in natural gas margin:

(Millions of Dollars)	Three Months Ended Sept. 30, 2010 vs. 2009	Nine Months Ended Sept. 30, 2010 vs. 2009
Conservation and DSM revenue and incentive (partially offset by expenses)	$ 4	$ 9
Rate increase (Minnesota interim)	1	4
Other, net	1	8
Total increase in natural gas margin	$ 6	$ 21

O&M Expenses — O&M expenses increased by approximately $43.2 million, or 9.3 percent, for the third quarter and by $96.5 million, or 6.8 percent for the nine months ended Sept. 30, 2010, compared with the same periods in 2009. The following table summarizes the changes in other O&M expenses:

(Millions of Dollars)	Three Months Ended Sept. 30, 2010 vs. 2009	Nine Months Ended Sept. 30, 2010 vs. 2009
Higher employee benefit costs	$ 14	$ 18
Higher plant generation costs	7	24
Higher labor costs	7	18
Higher nuclear plant operation costs	5	10
Higher insurance costs	1	8
Nuclear outage costs, net of deferral	-	10
Other, net	9	9
Total increase in other operating and maintenance expenses	$ 43	$ 97

- Higher employee benefit costs are primarily related to performance based incentive compensation as well as pension costs.
- Higher plant generation costs are primarily attributable to higher levels of scheduled maintenance and overhaul work as well as incremental operating costs associated with new generation facilities placed in service in the current year.
- Higher labor costs are primarily due to an increase in compliance requirements, higher overtime for storm restoration work, and a shift in labor resources from capital to O&M projects.
- Higher nuclear outage costs are due to the timing and cost of nuclear refueling outages.
- Higher insurance costs are due to general premium increases.

Conservation and DSM Program Expenses — Conservation and DSM program expenses increased by approximately $13.7 million, or 29.1 percent, for the third quarter and by $40.7 million, or 30.4 percent for the nine months ended Sept. 30, 2010, compared with the same periods in 2009. The higher expense is attributable to the expansion of programs and regulatory commitments. Conservation and DSM program expenses are generally recovered in our major jurisdictions concurrently through riders and base rates.

Depreciation and Amortization — Depreciation and amortization expenses increased by approximately $23.4 million, or 11.8 percent, for the third quarter and by $30.0 million, or 4.9 percent for the nine months ended Sept. 30, 2010, compared with the same periods in 2009. In September 2009, as a result of the Minnesota Public Utilities Commission (MPUC) decisions in the Minnesota electric rate case, NSP-Minnesota began recognizing a 10-year life extension of the Prairie Island nuclear plant for purposes of determining depreciation, effective Jan. 1, 2009. In addition, in June 2009, the MPUC extended the recovery period of decommissioning expense by 10 years for the Prairie Island and the Monticello nuclear plants. Excluding the one time decrease recognized in 2009, the change in depreciation expense from 2009 to 2010 is primarily due to Comanche Unit 3 going into service and normal system expansion.

Taxes (Other Than Income Taxes) — Taxes (other than income taxes) increased by approximately $2.9 million, or 3.6 percent, for the third quarter and by $15.2 million, or 6.6 percent for the nine months ended Sept. 30, 2010, compared with the same periods in 2009. The increase is primarily due to an increase in property taxes in Colorado and Minnesota.

Other Income (Expense), Net — Other income (expense), net increased by approximately $28.4 million for the third quarter and by $25.7 million for the nine months ended Sept. 30, 2010, compared with the same periods in 2009. The increase is primarily due to the corporate owned life insurance (COLI) settlement in July 2010.

Equity Earnings of Unconsolidated Subsidiaries — Equity earnings of unconsolidated subsidiaries increased by approximately $3.3 million for the third quarter and by $11.7 million for the nine months ended Sept. 30, 2010, compared with the same periods in 2009. The increase is primarily related to increased earnings from the equity investment in WYCO Development LLC, which includes a natural gas pipeline and a storage facility that began operating in 2008 and mid 2009, respectively.

Allowance for Funds Used During Construction, Equity and Debt (AFUDC) — AFUDC decreased by approximately $8.4 million for the third quarter and by $24.9 million for the nine months ended Sept. 30, 2010, compared with the same periods in 2009. The decrease was partially due to Comanche Unit 3 going into service and lower AFUDC rates.

Interest Charges — Interest charges increased by approximately $5.5 million, or 3.9 percent, for the third quarter and by $9.7 million, or 2.3 percent for the nine months ended Sept. 30, 2010, compared with the same periods in 2009. The increase is due to higher long-term debt levels to fund investment in our utility operations, partially offset by lower interest rates.

Income Taxes — Income tax expense for continuing operations increased by $30.6 million for the third quarter of 2010, compared with the same period in 2009. The increase in income tax expense was primarily due to an increase in pretax income. The effective tax rate for continuing operations was 34.7 percent for the third quarter of 2010, compared with 37.9 percent for the same period in 2009. The higher effective tax rate for the third quarter of 2009 was primarily due to the recognition of additional state unitary tax expense and the establishment of a valuation allowance against certain state tax credit carryovers that were expected to expire.

Income tax expense for continuing operations increased by $84.4 million for the nine months ended Sept. 30, 2010, compared with the same period in 2009. The increase in income tax expense was primarily due to an increase in pretax income, one time adjustments for a write-off of tax benefit previously recorded for Medicare Part D subsidies, and an adjustment related to the COLI Tax Court proceedings, partially offset by a reversal of a valuation allowance for certain state tax credit carryovers. The effective tax rate for continuing operations was 37.2 percent for the nine months ended Sept. 30, 2010, compared with 35.3 percent for the same period in 2009. The higher effective tax rate for the first nine months of 2010 was primarily due to a higher forecasted annual effective tax rate and the adjustments referenced above. Without these one time adjustments, the effective tax rate for continuing operations for the first nine months of 2010 would have been 35.3 percent. Xcel Energy expects the effective tax rate for 2010 ongoing earnings to be approximately 35 percent to 37 percent.

The higher forecasted annual effective tax rate for 2010 continuing operations as compared to 2009 was primarily due to reduced plant-related deductions and the elimination of tax benefits for Medicare Part D subsidies and research credits in 2010, partially offset by the nontaxibility of the Provident settlement in 2010.

Note 3. PSCo Reaches Agreement to Acquire Assets from Calpine

In April 2010, PSCo reached an agreement with Riverside Energy Center LLC and Calpine Development Holdings, Inc. to purchase the Rocky Mountain Energy Center and Blue Spruce Energy Center natural gas generation assets for $739 million.

The Rocky Mountain Energy Center is a 652 megawatt (MW) combined-cycle natural gas-fired power plant that began commercial operations in 2004. The Blue Spruce Energy Center is a 310 MW simple cycle natural gas-fired power plant that began commercial operations in 2003. Both power plants currently provide energy and capacity to PSCo under power purchase agreements, which were set to expire in 2013 and 2014.

The acquisition is subject to federal and state regulatory approvals including approval of the proposed recovery of costs. In June 2010, the Federal Trade Commission provided notice of the early termination of the waiting period under Hart-Scott-Rodino. In July 2010, the Federal Energy Regulatory Commission (FERC) issued an order approving the acquisition.

In September 2010, PSCo reached a partial settlement with the Colorado Public Utility Commission (CPUC) staff, the Colorado Independent Energy Association and the Office of Consumer Counsel (OCC), which provided for recovery of the revenue requirement (capital and O&M costs) associated with the transaction through an interim rider mechanism less a $3.9 million annual revenue reduction until PSCo implements new retail base rates. Additionally, in its next retail rate case, PSCo shall be allowed recovery of the net book value, based on the $739 million purchase price.

On Oct. 18, 2010, the CPUC approved the acquisition and the cost recovery settlement. The CPUC also required PSCo to file a rate case by April 30, 2012 to move the investment into rate base. The revenue requirements associated with the asset acquisition will continue to be recovered through the purchase capacity cost adjustment until final rates are implemented. Fuel costs will continue to flow through the energy cost adjustment and fuel cost adjustment mechanisms. The acquisition is expected to close in December 2010.

Note 4. Xcel Energy Capital Structure, Financing and Credit Ratings

Following is the capital structure of Xcel Energy:

(Billions of Dollars)	Sept. 30, 2010	Percentage of Total Capitalization
Current portion of long-term debt	$ 0.4	2 %
Short-term debt	-	-
Long-term debt	8.9	53
Total debt	9.3	55
Preferred equity	0.1	-
Common equity	7.6	45
Total capitalization	$ 17.0	100 %

Financing Plans — Xcel Energy issues debt and equity securities to refinance retiring maturities, reduce short-term debt, fund construction programs, infuse equity in subsidiaries, fund asset acquisitions and for other general corporate purposes. In addition to the periodic issuance and repayment of short-term debt, Xcel Energy and its utility subsidiaries' financing plans are as follows:

- In May 2010, Xcel Energy issued $550 million of 10-year unsecured debt with a coupon of 4.7 percent.
- In August 2010, NSP-Minnesota issued $250 million of five-year first mortgage bonds with a coupon of 1.95 percent and $250 million of 30-year first mortgage bonds with a coupon of 4.85 percent.
- In August 2010, Xcel Energy entered into a forward equity sales agreement to issue 21.85 million shares of common stock.
- PSCo plans to issue approximately $400 million of first mortgage bonds in the fourth quarter of 2010.
- Xcel Energy also anticipates issuing approximately $75 million of equity through the Dividend Reinvestment Program and various benefit programs in 2010.

Financing plans are subject to change, depending on capital expenditures, internal cash generation, market conditions and other factors.

Equity Forward Agreements — In August 2010, Xcel Energy entered into an equity forward agreement in connection with a public offering of Xcel Energy common stock. Under the equity forward agreements (Forward Agreements), Xcel Energy agreed to issue 21.85 million shares of its common stock, including an over allotment of 2.85 million shares.

The forward price used to determine cash proceeds due Xcel Energy at settlement of the equity forward instruments underlying the Forward Agreements will be calculated based on the August 2010 public offering price of Xcel Energy's common stock, adjusted for underwriting fees, as well as the federal funds rate, less a spread of 0.50 percent, and expected dividends on Xcel Energy's common stock during the period the instruments are outstanding. Xcel Energy may settle the equity forward instruments at any time up to the maturity date of May 15, 2011. Xcel Energy may also unilaterally elect cash or net share settlement at any time up to maturity, for all or a portion of the equity forward instruments.

At Sept. 30, 2010, the equity forward instruments could have been settled with physical delivery of 21.85 million shares to the banking counterparty in exchange for cash of $450.0 million. Assuming required notices and actions occurred, the forward instruments could also have been settled at Sept. 30, 2010 with delivery of cash of approximately $38.1 million or approximately 1.65 million shares of common stock.

Xcel Energy expects to settle the forward equity agreement by physically delivering the 21.85 million shares of common equity in the fourth quarter of 2010.

Credit Facilities — As of Oct. 20, 2010, Xcel Energy and its utility subsidiaries had the following committed credit facilities available to meet its liquidity needs:

(Millions of Dollars)	Facility	Drawn[(a)]	Available	Cash	Liquidity	Maturity
NSP-Minnesota	$ 482.2	$ 5.3	$ 476.9	$ 56.8	$ 533.7	December 2011
PSCo	675.1	4.5	670.6	19.1	689.7	December 2011
SPS	247.9	-	247.9	4.3	252.2	December 2011
Xcel Energy – Holding Company	771.6	47.1	724.5	0.8	725.3	December 2011
NSP-Wisconsin[(b)]	-	-	-	13.2	13.2	
Total	$ 2,176.8	$ 56.9	$ 2,119.9	$ 94.2	$ 2,214.1	

(a) Includes direct borrowings, outstanding commercial paper and letters of credit.
(b) NSP-Wisconsin does not have a separate credit facility; however, it has a short-term borrowing agreement with NSP-Minnesota.

Credit Ratings — Access to reasonably priced capital markets is dependent in part on credit and ratings. The following ratings reflect the views of Moody's Investors Service (Moody's), Standard & Poor's Rating Services (Standard & Poor's), and Fitch Ratings (Fitch).

As of Oct. 20, 2010, the following represents the credit ratings assigned to various Xcel Energy companies:

Company	Credit Type	Moody's	Standard & Poor's	Fitch
Xcel Energy	Senior Unsecured Debt	Baa1	BBB+	BBB+
Xcel Energy	Commercial Paper	P-2	A-2	F2
NSP-Minnesota	Senior Unsecured Debt	A3	A-	A
NSP-Minnesota	Senior Secured Debt	A1	A	A+
NSP-Minnesota	Commercial Paper	P-2	A-2	F1
NSP-Wisconsin	Senior Unsecured Debt	A3	A-	A
NSP-Wisconsin	Senior Secured Debt	A1	A	A+
PSCo	Senior Unsecured Debt	Baa1	A-	A-
PSCo	Senior Secured Debt	A2	A	A
PSCo	Commercial Paper	P-2	A-2	F2
SPS	Senior Unsecured Debt	Baa1	A-	BBB+
SPS	Commercial Paper	P-2	A-2	F2

Moody's highest credit rating for debt is Aaa and lowest investment grade rating is Baa3. Both Standard & Poor's and Fitch's highest credit rating for debt are AAA and lowest investment grade rating is BBB-. Moody's prime ratings for commercial paper range from P-1 to P-3. Standard & Poor's ratings for commercial paper range from A-1 to A-3. Fitch's ratings for commercial paper range from F1 to F3. A security rating is not a recommendation to buy, sell or hold securities. Such rating may be subject to revision or withdrawal at any time by the credit rating agency and each rating should be evaluated independently of any other rating.

Note 5. Rates and Regulation

NSP-Minnesota Gas Rate Case — In November 2009, NSP-Minnesota filed a request with the MPUC to increase Minnesota natural gas rates by $16.2 million for 2010, based on a return on equity (ROE) of 11 percent, an equity ratio of 52.46 percent and a rate base of $441 million. The overall request seeks an additional $3.5 million, effective Jan. 1, 2011, for recovery of pension funding costs necessary to comply with federal law. In December 2009, the MPUC approved an interim rate increase of $11.1 million, subject to refund. Interim rates went into effect on Jan. 11, 2010.

NSP-Minnesota made several adjustments and is currently seeking an increase of $10.0 million based on a 10.6 percent ROE. The Office of Energy Security (OES) revised its case and is now recommending an increase of approximately $7.5 million based on a 10.09 percent ROE. NSP-Minnesota and the Minnesota Office of Attorney General (OAG) agreed on treatment of pension issues, for future rate proceedings, and NSP-Minnesota is no longer seeking a 2011 step-in of pension expense. The OAG continued to recommend further adjustments in bad debt expense, distribution O&M expenses and the cost of debt.

In October 2010, the administrative law judge (ALJ) issued his report and recommended a rate increase of approximately $8 million, based on a 10.09 percent ROE. A decision from the MPUC is anticipated late in the fourth quarter of 2010.

NSP-Wisconsin - 2010 Electric Rate Case Reopener — In August 2010, NSP-Wisconsin filed a request with the Public Service Commission of Wisconsin (PSCW) to reopen the 2010 rate case and increase retail electric rates for 2011 by $29.1 million, or 5.4 percent, based on a forecast 2011 test year.

The requested increase in electric rates is primarily related to production and transmission fixed charges, specifically new investment in cleaner sources of energy and transmission lines to help reliably meet customers' electric needs as well as forecast cost increases for fuel and purchased power. Partially offsetting these increased costs is a refund of the Wisconsin customers' share of excess funds in the Monticello nuclear generating plant external decommissioning fund. No changes are requested to the capital structure or ROE authorized by the PSCW in the 2010 base rate case.

The major cost components of the requested increase are summarized below:

(Millions of Dollars)		**Request**
Production and transmission fixed charges	$	19.3
Fuel and purchased power		12.1
Other		3.5
Monticello nuclear decommissioning fund refund		(5.8)
Total	$	29.1

The PSCW held a pre-hearing conference in September 2010 and established the following procedural schedule:

- Staff and intervenor direct testimony due Nov. 5, 2010;
- Rebuttal testimony due Nov. 12, 2010;
- Surrebuttal testimony due Nov. 16, 2010;
- Technical and public hearings scheduled for Nov. 17, 2010; and
- Initial brief due Dec. 6, 2010.

NSP-Wisconsin has requested that the PSCW approve this application to allow new rates to be effective Jan. 1, 2011.

PSCo - Colorado Clean Air-Clean Jobs Act — The Colorado Clean Air-Clean Jobs Act (CACJA) was signed into law in April 2010. The CACJA required PSCo to file a comprehensive plan with the CPUC by Aug. 15, 2010 to reduce annual emissions of nitrogen oxide (NOx) by at least 70 to 80 percent from 2008 levels from the coal-fired generation identified in the plan. The plan must consider emission controls, plant refueling, or plant retirement of at least 900 MW of coal-fired generating units in Colorado by Jan. 1, 2018. The legislation further encourages PSCo to submit long-term gas contracts to the CPUC for approval. If approved, PSCo would be entitled to recover the costs it incurs under these long-term gas contracts, notwithstanding any change in the market price of natural gas during the term of the contract.

Pursuant to the CACJA, PSCo is authorized to recover the costs that it prudently incurs in executing an approved emission reduction plan and is allowed a return on construction work in progress (CWIP) on plan investments. In addition, if early action is taken to retire or convert units to natural gas, and PSCo shows that the costs of the plan would contribute to an earnings deficiency, additional relief, including a more comprehensive rider to recover other plant costs such as depreciation and O&M expenses, or a multi-year rate plan are allowed. The CACJA permits the CPUC to consider interim rate increases after Jan. 1, 2012 while the rate filing is pending.

In August 2010, PSCo filed its preferred plan with the CPUC. PSCo's recommended plan has three key components:

- Retires 900 MW of coal generation at its Valmont (186 MW) in 2017 and Cherokee (717 MW) in 2022;
- Repowers its Cherokee generating facility with efficient, natural gas generation of 883 MW (589 MW in 2015 and 314 MW in 2022). PSCo also will switch to natural gas generation at the 111 MW Arapahoe Unit 4 generating facility in 2013; and
- Retrofits about 950 MW of coal-fired generation at the Pawnee (505 MW) and Hayden (446 MW) generating facilities with modern emission control technology.

The plan would reduce emissions of NOx from the targeted plants by 77 percent at the end 2017, and by 89 percent at the end of 2022. In addition, when compared to 2008 levels, the plan would reduce sulfur dioxide (SO_2) emissions by 84 percent and mercury emissions by 85 percent for the power plants targeted under the plan by 2023. The plan also allows PSCo to meet Colorado's statewide carbon dioxide reduction goal of 20 percent before the 2020 target.

The total cost of the plan, if approved by the CPUC, would result in new construction of approximately $1.4 billion over the next 12 years. The rate impact of the proposed plan is expected to increase future bills on average by 1.5 percent annually over the next ten years. The recommended plan costs less than retrofitting all of these units with emission control equipment. The estimated cost of the plan for the years 2011 through 2017 is shown in the table below:

(Millions of Dollars)	2011	2012	2013	2014	2015	2016	2017	Total
Combined cycle	$ 16.0	$ 81.0	$ 203.1	$ 105.4	$ 103.1	$ 25.9	$ -	$ 534.5
Pollution control unit	69.6	82.8	66.3	93.4	26.1	8.6	-	346.8
Transmission	1.2	3.1	3.1	4.5	11.4	-	-	23.3
Gas pipeline	5.9	6.1	57.2	40.7	-	-	-	109.9
Total	$ 92.7	$ 173.0	$ 329.7	$ 244.0	$ 140.6	$ 34.5	$ -	$ 1,014.5

PSCo also proposed to implement a new emission reduction adjustment rate to go into effect around January 2011. This adjustment clause seeks to recover a return on the CWIP for electric investments made pursuant to the plan and also includes the recovery of other plant related costs, such as higher depreciation expense, incurred under the emissions reduction plan. The 2011 expected increase would be approximately $14.1 million.

In September 2010, 51 witnesses filed answer testimony representing over 20 parties in the case. Coal interests generally opposed PSCo's plan and advocated for scenarios in which emissions control retrofits were installed. Gas interests and environmental groups advocated for accelerating the time line of PSCo's proposed plan and advocated for the inclusion of other generation alternatives and energy efficiency. The City and County of Denver, Colo., and the County of Boulder, Colo. supported the plan. Several parties sought changes to the regulatory recovery provisions proposed by PSCo. Hearings began on Oct. 21, 2010 and the CPUC is scheduled to issue a decision by Dec. 15, 2010.

In October 2010, the CPUC ruled that based on the Colorado Department of Public Health and Environment's (CDPHE) interpretation of certain statutory provisions related to reasonably foreseeable air quality regulations, that PSCo's plan to take actions beyond 2017 failed to meet the standards of the CACJA. As a result, PSCo filed supplemental testimony on Oct. 25, 2010 recommending that if the CPUC or the CDPHE can't find the original plan acceptable, that the preferred plan is to install selective catalytic reduction on its Cherokee Unit 4 by 2017.

PSCo 2010 Electric Rate Case — In December 2009, the CPUC approved a rate increase of approximately $128.3 million; however, due to the delay in Comanche Unit 3 coming online, the CPUC approved PSCo's proposal to phase in the approved electric rate increase to reflect the actual cost of service. Under the plan, the following increases have or will be implemented:

- A rate increase of $67 million was implemented on Jan. 1, 2010 because of the delay of the in-service date of Comanche Unit 3;
- Base rates were increased to recover $123 million annually, on May 14, 2010 when Comanche Unit 3 went into service, including an additional $2 million of recovery for long-term debt interest in the working capital calculation granted under reconsideration; and
- Base rates will increase to recover approximately $130 million annually on Jan. 1, 2011 to reflect 2011 property taxes.

A second phase of the rate case addressed changes to rate design. The new rates, approved by the CPUC, went into effect on June 1, 2010. In this phase of the proceeding, the CPUC approved tiered summer rates for residential customers and seasonally differentiated rates for other customer classes, which will impact the timing of revenue collection, as compared to the previous rate design, depending on customer response. Third quarter and year to date electric revenue and margin for 2010 were positively impacted by approximately $45 million and $53 million, respectively, related to the implementation of such rate design and seasonal rates. Seasonal rates are designed to be revenue neutral on an annual basis. However, the quarterly pattern of revenue collection is expected to be different than in the past as seasonal rates are higher in the summer months and lower throughout the remainder of the year. It is anticipated that this positive electric revenue and margin trend will partially reverse in the fourth quarter.

PSCo - Wholesale Rate Case — In 2009, PSCo filed a request with the FERC to increase electric rates to its firm wholesale customers by $30.7 million based on a 12.5 percent ROE, a 58 percent equity ratio and a rate base of $315 million.

During the summer of 2010, PSCo filed blackbox settlements with all of its wholesale customers. The settlements provided for new rates reflecting an electric rate increase of approximately $21.0 million for these customers effective in July, 2010. In addition, on Jan. 1, 2011, an additional step rate increase of $1.0 million will be implemented for property taxes associated with Comanche Unit 3. The terms of the settlements provide for lower depreciation expense than requested and for certain capacity costs to be recovered through the fuel clause until those contracts expire. The FERC approved the settlements in October 2010.

SPS - Texas Retail Base Rate Case **—** In May 2010, SPS filed an electric rate case in Texas seeking an annual base rate increase of approximately $62 million. On a net basis, the request seeks to increase customer bills by approximately $53.4 million or 7 percent. The rate filing is based on a 2009 test year adjusted for known and measurable changes, a requested ROE of 11.35 percent, an electric rate base of $1.031 billion and an equity ratio of 51.0 percent. The following table summarizes the request:

(Millions of Dollars)	Request
Proposed base rate increase	$ 62.0
Franchise fee cost recovery	8.7
Nitrogen oxide emission allowances	0.8
Purchased capacity recovery factor	(13.5)
Transmission cost recovery factor	(4.6)
Adjusted rate increase	$ 53.4

The filing with the Public Utility Commission of Texas (PUCT) also includes a request to reconcile SPS' fuel and purchased power costs for calendar years 2008 and 2009. As of Dec. 31, 2009, SPS had a fuel cost under-recovery of approximately $3.3 million.

In September 2010, SPS filed an agreement with the intervening parties to abate, or suspend, the procedural schedule for a 90-day extension in this case. SPS made a filing on Oct. 19, 2010 showing the on-going savings related to the Lubbock sale. As part of the agreement to abate the procedural schedule, the parties agreed that the effective date of implementation of SPS' new rates is expected to be Feb. 16, 2011. This will be accomplished either by establishing interim rates effective on Feb. 16, 2011; or by making the final rates effective retroactive back to Feb. 16, 2011 from the date SPS implements final rates, after the PUCT issues its final order.

The revised procedural schedule is as follows:

- Intervenor direct testimony due Jan. 18, 2011;
- PUCT staff direct testimony due Jan. 25, 2011;
- PUCT staff and intervenor cross rebuttal testimony due Feb. 1, 2011;
- SPS rebuttal testimony due Feb. 8, 2011; and
- Hearings on Feb. 21, 2011 through March 11, 2011.

Note 6. Xcel Energy Ongoing Earnings Guidance

Xcel Energy's 2010 ongoing earnings guidance is $1.55 to $1.65 per share and expects earnings to be in the upper half of the range. Key assumptions related to ongoing earnings are detailed below:

- Normal weather patterns are experienced for the rest of the year.
- Weather-adjusted retail electric utility sales increase approximately 1.2 percent to 1.4 percent.
- Weather-adjusted retail firm natural gas sales increase approximately 0 percent to 1 percent.
- Increased revenue due to the full year impact of 2009 electric rate cases in Colorado, Texas and New Mexico, along with the 2010 electric rate increases in Colorado.
- Constructive outcomes in all regulatory proceedings.
- Increased rider revenue recovery of approximately $30 million.
- O&M expenses are projected to increase approximately 8 percent to 9 percent.
- Depreciation expense is projected to increase $35 million to $45 million.
- Interest expense is projected to increase approximately $20 million to $30 million.
- AFUDC — equity is projected to decrease approximately $20 million.
- The effective tax rate is approximately 35 percent to 37 percent.
- Average common stock and equivalents total approximately 465 million shares.

Xcel Energy's 2011 ongoing earnings guidance is $1.65 to $1.75 per share. Key assumptions related to ongoing earnings are detailed below:

- Normal weather patterns are experienced for the year.
- Weather-adjusted retail electric utility sales, adjusted for the sale of the Lubbock distribution assets, grow approximately 1 percent.
- Weather-adjusted retail firm natural gas sales are projected to be relatively flat.
- Constructive outcomes in all rate case and regulatory proceedings.
- Increased rider revenue recovery of approximately $35 million.
- O&M expenses are projected to increase 3 percent to 4 percent.
- Depreciation expense is projected to increase $55 million to $65 million.
- Interest expense is projected to increase approximately $30 million to $40 million.
- AFUDC — equity is projected to be relatively flat.
- The effective tax rate is approximately 35 percent to 37 percent.
- Average common stock and equivalents total approximately 485 million shares.

Note 7. Non-GAAP Reconciliation

Ongoing earnings exclude the impact of Internal Revenue Service (IRS) tax and interest adjustments related to COLI program, the write-off of previously recognized tax benefits relating to Medicare Part D subsidies due to the recently enacted Patient Protection and Affordable Care Act and a settlement related to the previously discontinued COLI program.

COLI Settlement
In July 2010, Xcel Energy, PSCo and P.S.R. Investments Inc. (PSRI) entered into a settlement agreement with Provident Life & Accident Insurance Company (Provident) related to all claims asserted by Xcel Energy, PSCo and PSRI against Provident in a lawsuit associated with the discontinued COLI program. Under the terms of the settlement, Xcel Energy, PSCo, and PSRI were paid $25 million by Provident and Reassure America Life Insurance Company resulting in approximately $0.05 of non-recurring earnings per share, in the third quarter of 2010. The $25 million proceeds are not subject to income taxes.

Impact of the Patient Protection and Affordable Care Act — Medicare Part D
In March 2010, the Patient Protection and Affordable Care Act was signed into law. The law includes provisions to generate tax revenue to help offset the cost of the new legislation. One of these provisions reduces the deductibility of retiree health care costs to the extent of federal subsidies received by plan sponsors that provide retiree prescription drug benefits equivalent to Medicare Part D coverage, beginning in 2013. Based on this provision, Xcel Energy is subject to additional taxes and is required to reverse previously recorded tax benefits in the period of enactment. Xcel Energy expensed approximately $17 million, or $0.04 per share, of previously recognized tax benefits relating to Medicare Part D subsidies during the first quarter of 2010. Xcel Energy does not expect the $17 million of additional tax expense to recur in future periods.

PSRI
During 2007, Xcel Energy reached a settlement with the IRS related to a dispute associated with its COLI program. These COLI policies were owned and managed by PSRI, a wholly owned subsidiary of PSCo. As a follow on to the 2007 IRS COLI settlement, as part of the Tax Court proceedings, during the first quarter of 2010, Xcel Energy and the IRS reached an agreement in principle after a comprehensive financial reconciliation of Xcel Energy's statements of account, dating back to tax year 1993. Upon completion of this review, PSRI recorded a net non-recurring tax and interest charge of approximately $10 million (including $7.7 million tax expense and $2.3 million interest expense, net of tax), or $0.02 per share during the first quarter. During the third quarter of 2010, Xcel Energy and the IRS came to final agreement on the applicable interest netting computations related to these tax years. Accordingly, PSRI recorded a reduction to expense of $0.6 million, net of tax, during the third quarter of 2010. Xcel Energy anticipates that the Tax Court proceedings will be dismissed in fourth quarter 2010.

Xcel Energy's management believes that ongoing earnings provide a meaningful comparison of earnings results and is representative of Xcel Energy's fundamental core earnings power. Xcel Energy's management uses ongoing earnings internally for financial planning and analysis, for reporting of results to the Board of Directors, in determining whether performance targets are met for performance-based compensation, and when communicating its earnings outlook to analysts and investors.

The following table provides a reconciliation of ongoing earnings to GAAP earnings:

(Thousands of Dollars)	Three Months Ended Sept. 30, 2010	Three Months Ended Sept. 30, 2009	Nine Months Ended Sept. 30, 2010	Nine Months Ended Sept. 30, 2009
Ongoing earnings	**$ 287,002**	**$ 222,131**	**$ 618,836**	**$ 516,970**
Medicare Part D	-	-	(16,948)	-
COLI settlement and PSRI	25,486	(338)	13,565	(2,295)
Total continuing operations	**312,488**	**221,793**	**615,453**	**514,675**
Income (loss) from discontinued operations	(182)	(965)	3,747	(2,673)
GAAP earnings	**$ 312,306**	**$ 220,828**	**$ 619,200**	**$ 512,002**

XCEL ENERGY INC. AND SUBSIDIARIES
EARNINGS RELEASE SUMMARY (UNAUDITED)
(amounts in thousands, except earnings per share)

	Three Months Ended Sept. 30,	
	2010	**2009**
Operating revenues:		
Electric and natural gas revenues	$ 2,611,511	$ 2,298,556
Other	17,276	16,006
Total operating revenues	2,628,787	2,314,562
Income from continuing operations	312,488	221,793
Loss from discontinued operations	(182)	(965)
Net income	312,306	220,828
Earnings available to common shareholders	311,246	219,768
Weighted average diluted common shares outstanding	462,019	457,453
Components of Earnings per Share — Diluted		
Regulated utility — continuing operations	0.66	0.52
Holding company and other costs	(0.04)	(0.04)
Ongoing[(a)] diluted earnings per share	**0.62**	**0.48**
COLI settlement, PSRI and Medicare Part D [(a)]	0.05	-
Earnings per share from continuing operations	**0.67**	**0.48**
Earnings per share from discontinued operations	-	-
GAAP diluted earnings per share	$ **0.67**	$ **0.48**

	Nine Months Ended Sept. 30,	
	2010	**2009**
Operating revenues:		
Electric and natural gas revenues	$ 7,687,365	$ 6,973,368
Other	56,648	52,819
Total operating revenues	7,744,013	7,026,187
Income from continuing operations	615,453	514,675
Earnings (loss) from discontinued operations	3,747	(2,673)
Net income	619,200	512,002
Earnings available to common shareholders	616,020	508,822
Weighted average diluted common shares outstanding	460,722	456,729
Components of Earnings per Share — Diluted		
Regulated utility — continuing operations	1.44	1.23
Holding company and other costs	(0.10)	(0.11)
Ongoing[(a)] diluted earnings per share	**1.34**	**1.12**
COLI settlement, PSRI and Medicare Part D [(a)]	(0.01)	(0.01)
Earnings per share from continuing operations	**1.33**	**1.11**
Earnings per share from discontinued operations	0.01	-
GAAP diluted earnings per share	$ **1.34**	$ **1.11**
Book value per share	$ 16.53	$ 15.76

(a) See Note 7.